PROCEEDINGS, Eighteenth Workshop on Geothermal Reservoir Engineering
Stanford University, Stanford, California, January 26-28, 1993
SGP-TR-145

WELLBORE SIMULATION - CASE STUDIES

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ABSTRACT

The use of a wellbore simulator, WELLSIM, to characterise the effects of multi-feed inflow on wellbore pressure-temperature characteristics, and diameter changes to a well on the deliverability curve, is discussed. Matching analyses are performed with the simulator on a well which has a number of two-phase and liquid infeeds, and it is demonstrated that good matches to both pressure and temperature profiles can be achieved. The significance of the reservoir/feed response curve for a steam well is illustrated, and the optimisation of wellbore diameter is shown to be related to whether the discharge is wellbore or reservoir controlled.

INTRODUCTION

Studies of flow in a wellbore have become important in recent years as reservoir engineers and operators have sought to improve reservoir simulation techniques and the corresponding results, and to optimise well output. This study is based on a wellbore simulator, of which a number are described in the literature (e.g. Barelli et al., 1982; Bjornsson, 1987; and Hadgu, 1989).

The basis of most of these simulators is the one-dimensional steady flow momentum equations, with closing equations provided from the two-phase flow literature for wells supplying fluid from a liquid or two-phase reservoir. In general, for such a simulator, five flow regimes are recognised: bubble, slug, churn, annular and mist, with transition and pressure drop relationships dependent on the user's choice. A full discussion of some of the available regime transition equations, and pressure drop predictions is in Hadgu (1989).

Fluid composition, that is, the water and gas chemistry, has a significant influence on the well performance. Well geometry and the location and number of feed zones are other major factors influencing well performance. Modern wellbore simulators will therefore have a pressure/temperature/volume (PVT) package capable of accurately specifying fluid properties over a range of pressure and chemistry. The wellbore simulator used in this study is a commercially-available software package, WELLSIM, developed by Geothermal Energy New Zealand Limited (GENZL) and Auckland UniServices Limited, based on the work of Hadgu (1989). The structure of the program is described in Gunn and Freeston (1991a). The latest version of the WELLSIM simulator gives the user: a choice of five different two-phase flow correlations for evaluating pressure drop; the PVT package for H_2O-CO_2-NaCl systems described in Andersen et al. (1992); a pre-processing module to check the accuracy of input data; a matching analysis module; and, a method for assessing the consistency of downhole pressure and temperature measurements, termed lower bound analysis.

A comparison of the five two-phase flow correlations as implemented in WELLSIM has been performed by Probst et al. (1992), and a description of the preprocessor, matching and lower bound modules is in Gunn et al. (1992). WELLSIM is also capable of analysing multi-feed zone wells, although in order to accurately and uniquely characterise flow in such a well, feed zone input data has to be known precisely; such data is not often available.

WELLSIM is a steady-state wellbore simulator, and so assumes that the simulated conditions do not vary significantly with respect to time, and thus the discharge is considered to be "stable". The changes with time that occur in wellhead conditions due to changes in the reservoir are outside the scope of this study.

The wellhead or deepest feed input parameters to the simulator, include: pressure; temperature; enthalpy; mass flowrate; fluid type (i.e. liquid, superheated steam, or two-phase); fluid impurity content (i.e. the amount of dissolved solids and non-condensable gases); and, dryness fraction.

OUTPUT CURVES

The output curve for a well is the plotted relationship of discharging mass flowrate against wellhead pressure. This is sometimes referred to as either a "deliverability curve" or "productivity curve". The form of this relationship can determine the suitability of a well for energy production. The wellhead pressure can be controlled through choke valves which in turn alters the discharging mass flowrate of the well, and thus the output curve can be found directly from well testing.

Wellbore simulators can be used to estimate the full output curve based on one or two measured points, saving additional well tests. Furthermore, a simulator can be applied to predicting the effects of changes in well design on well productivity. Hadgu and Freeston (1986) and Freeston and Hadgu (1986) describe the application of wellbore simulators to management problems in a geothermal field, and in particular examine the effects of changes in well design. Barnett (1989) describes a theoretical study of the effect of wellbore diameter on well output for a well in the Eburru geothermal field in Kenya.

Barnett (1989) discusses that where a reservoir is sufficiently permeable it can supply fluid at a greater rate than that which the well is able to deliver to the surface. Such behaviour is termed *wellbore controlled flow*, as it occurs when the pressure drop up the well is substantially greater than the *pressure drawdown*. Pressure drawdown in this study does not refer to pressure changes in the reservoir over time, but to the pressure difference between the static reservoir pressure at the primary feed zone when the well is shut-in, and the pressure at that feed whilst the well is discharging. It can be inferred that when wellbore controlled flow occurs, larger well diameters should provide more favourable well output characteristics than smaller wells. However, the important consideration is as to whether the increased cost of the larger wellbore is sufficiently offset by the value of the greater rate of steam flow that might be delivered.

RESERVOIR/FEED RESPONSE CURVES

The reservoir/feed response curve is similar to an output curve for the well, but at depth, rather than at the wellhead. It is also a function of mass flowrate against pressure, although in this case it is the pressure at the feed that is of interest.

The most desirable method of determining the reservoir/feed response curve is to measure it directly. By taking downhole pressure and temperature measurements during discharge of the well at a number of different mass flowrates, pairs of mass flowrate and feed pressure can be observed. In general, if these measurements have been taken with suitable accuracy, the data can be fitted to one of a number of typical equations describing the reservoir/feed response curve. The equations used to fit such curves are termed "drawdown relationships".

Drawdown relationships express the pressure drawdown as a function of the mass flowrate of the fluid entering the wellbore from the reservoir. This pressure drop or drawdown from undisturbed (i.e. static) conditions in the reservoir, to full flow in the wellbore, is caused by a combination of laminar, turbulent, and wellbore entrance effects, amongst others.

For two-phase feeds, or feeds with high mass flowrates, one general form of this relationship is shown in equation (1) (e.g. Gunn and Freeston, 1991b).

$$p_r - p_f = aW + bW^2 \qquad (1)$$

where: p_r = undisturbed (static) reservoir pressure; p_f = feed zone pressure; W = feed zone mass flowrate; a = first order drawdown parameter (a constant); and, b = second order drawdown parameter (a constant).

Drawdown relationships for dry or superheated steam feeds have another form that is also second order, but in addition includes a "drawdown exponent" as seen below in equation (2), (e.g. Bodvarsson and Witherspoon, 1985).

$$W = C(p_r^2 - p_f^2)^n \qquad (2)$$

where: C = steam drawdown parameter/coefficient; and n = steam drawdown exponent.

Where feed zone mass flowrate and pressure measurements are available, the unknown drawdown parameters in the appropriate expression from above can be found directly. It is unlikely that the relationships will fit the measured data exactly, but the unknown parameters can be varied until the best fit is found.

It is generally assumed that the reservoir/feed response can be considered independent of well design and diameter. This assumption means that once appropriate drawdown parameters are established for a particular well, based on observed conditions, then the effect that any desired change in well design has on the output curve for that well can be predicted. This can be done by performing a series of wellbore simulations over a range of mass flowrates using deepest feed zone conditions as the input parameters, and by specifying the change in well design. The results of the simulations provide the estimated new wellhead pressure for each discharging mass flowrate and thus the output curve for the new design. The change in productivity can be found by comparing the new and existing output curves at the operating wellhead pressure.

PRESSURE/TEMPERATURE PROFILES

Measurements of downhole pressure and temperature are difficult to obtain in a flowing well; they are mass flow limited where wireline-type logging is used, due to drag of the toolhead. Simulation at higher mass flowrates is therefore useful in characterising feed zone characteristics.

The mass and energy equations governing the conditions at a secondary feed are presented in Bjornsson (1987), who postulates six possible flow directions and conditions in the wellbore close to the feed zone, depending on the characteristics of the feed zones (inflow or outflow) and the type of well behaviour, production or injection. As noted above, the values of secondary feed enthalpy and mass flowrate are not usually available as simulator input conditions, but Bjornsson (1987) suggested that varying their magnitude until good matching is achieved can at least provide feasible estimates. However, the solution can be non-unique because more than one set of feed zone parameters might satisfy the data. The decision as to which set of parameters is the most accurate may require other independent data, such as the use of geochemical information at a feed zone to define an enthalpy.

The feed zone is generally assumed in a wellbore simulator to act at a point around which pressures are invariant. In reality, mixing of fluids and the subsequent changes in properties of the mixed fluid will occur over a zone or region rather than at a point.

Where two feeds contribute fluids of different temperature, it is possible that the downhole temperature profile will exhibit a discontinuity about the feed point. Such discontinuities will be pronounced where the fluid causes a phase transition at the feed. This will occur when a high enthalpy two-phase fluid enters the well above a liquid feed, or alternatively a lower enthalpy liquid feed overlies a two-phase zone. The well examined in Case Study 2 of this paper exhibits such a temperature discontinuity.

CASE STUDY 1 - WELL OUTPUT

For the first case study, WELLSIM has been used to assess the possible benefits of drilling larger wells in a vapor-dominated field. The field already has a number of producing wells, each with a $9\frac{5}{8}$" production casing and 7" liner. The proposed larger well design involves a $13\frac{3}{8}$" casing and $10\frac{3}{4}$" liner. Measured output curves are available for most wells, but measurements of feed mass flowrate and pressure are not.

WELLSIM has initially been used to determine the reservoir/feed response curves for each well, based on the observed wellhead conditions. The results of these simulations thus produce a typical range of responses throughout the reservoir. A "representative well" can then be modelled. This well has been simulated over the range of typical feed responses and depths for both the current well design and the proposed larger well design, in order to predict the relative increase in production that might be recognised by drilling larger wells in future.

Points on the reservoir/feed response curves for each well are estimated from the results of a series of wellhead/down simulations, using points on each measured output curve as simulator input parameters. The casing and liner sizes and the feed depth are also specified, assuming a single feed, as are the other input parameters such as enthalpy and gas content. WELLSIM contains a preprocessing module which ensures that wellhead or feed input parameters are complete and/or consistent. For each pair of output mass flow and pressure measurements, the simulation produces pairs of feed mass flow rate and pressure at the feed depth. With an assumed undisturbed reservoir pressure, values of C and n can be estimated from equation (2). A least squares best fit value for these drawdown parameters can then be determined.

The representative well has been modelled with a typical feed enthalpy of 2800 kJ/kg, a gas content of 0.15% by weight, and no salts. An undisturbed reservoir pressure of 36 bara has been assumed.

Once the values of the feed productivity (C) were determined for the actual wells, three different values of C were selected for the representative well as being typical of actual well behaviour. A value of $n = 0.75$ was used in all cases, as it was found that this value was applicable to all the actual wells. As noted also by Rumi (1972), using a field-wide value for n, reduces the complexity of the problem, and allows all the values to be compared on the same basis, as they all have the same units.

The first value is $C = 0.75$ t/(hr.bara$^{1.5}$). It is suggested that this value can be considered to relate to a steam well that is a good producer (around 8 MW), either with a fairly good permeability, or with a fairly large negative skin factor.

The second value used is $C = 0.375$ t/(hr.bara$^{1.5}$) which is half the previous value. This value is probably more typical of the mean value of C for wells drilled in the production phase. The final value used is $C = 1.5$ t/(hr.bara$^{1.5}$) and it is suggested that this value is typical of the most productive wells in the field.

The current and larger well designs have both been modelled as having a casing shoe at 900m. For each value of C, three cases have been simulated with the primary feed at 1000 m, 1300 m, and also at 1600 m.

RELATIONSHIP BETWEEN PERMEABILITY AND WELL PRODUCTIVITY

The effect of a variation in feed productivity on the predicted increase in production from the current to the larger well design is shown in Figure 1. For each case the increase in production is considered at the three different primary feed depths and at operating pressures of 10 bara and 15 bara.

It can be clearly seen that the more productive the feed, then the greater is the increase in production between two well designs. From this conclusion it can be inferred that a well that intersects highly permeable regions stands to benefit significantly from a larger casing and liner.

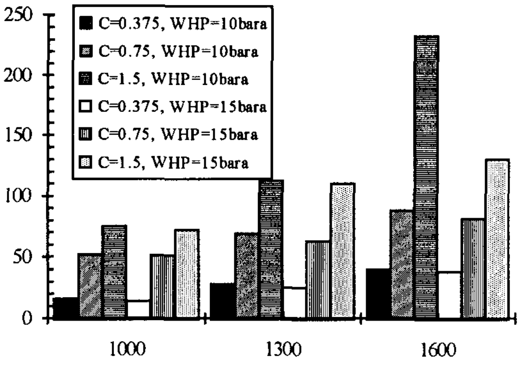

Figure 1: Effects of variations in feed productivity (*C*) and feed depth, on the production increase between the current and larger well designs for the representative well.

This result demonstrates the effect of wellbore controlled flow, because the wellbore has more control over the flow for high values of *C*. In other words, the wellbore diameter affects the flow more where the feed zones are highly productive. The converse is also true. Where *C* is low, then the flow is controlled more by the reservoir/feed response relationship. This is clearly illustrated in Figure 2, which presents a selection of the cases run. Of the cases where $C = 0.375$ t/(hr.bara$^{1.5}$) the reservoir/feed response curve lies only just above the output curve that provides the greatest well productivity. At a particular operating pressure any well must have an output that is less than the feed mass flowrate found at that pressure on the response curve.

For example, with $C = 0.375$, the feed mass flowrate at a feed pressure of 15 bara is 70 t/hr. This means that the production can never be more than 70 t/hr if the wellhead operating pressure is 15 bara. From Figure 2, the most productive output curve where $C = 0.375$ is for the larger well design with a 1000 m feed. The difference between the production at 15 bara, and the feed mass flowrate at 15 bara is only 4 t/hr. This means that increasing the diameter of the well any further serves little purpose.

In general the output curves for the larger well design where $C = 0.375$ come very close to the reservoir/feed response curve. The feed zone depth has less effect on the production with the larger well design. This indicates that using a $13\frac{3}{8}$" casing and $10\frac{3}{4}$" liner can be considered relatively optimal for these type of vapor-dominated reservoir conditions, as a bigger well cannot improve production significantly. Such fairly "flat" reservoir/feed response curves can be considered more indicative of reservoir controlled flow.

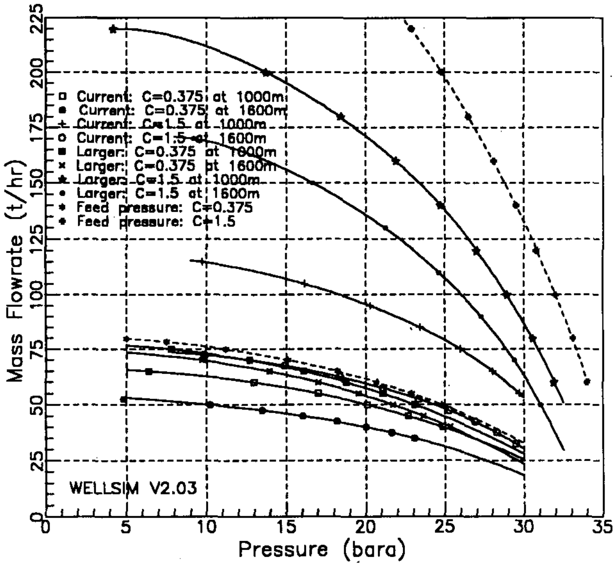

Figure 2: A selection of the predicted output curves for the representative well.

CASE STUDY 2 - MULTIPLE FEED WELL

In the second case study WELLSIM has been used to attempt to characterise a multiple feed well. The well selected is from a liquid-dominated reservoir with very low concentrations of dissolved salts and non-condensable gases. The production casing is $9\frac{5}{8}$", and the liner is $7\frac{5}{8}$" running from 1218 m to 2879 m. The well deviates by 23° from the vertical below 500 m. The main permeable zone lies between 1898 - 2084 m. Minor permeable zones are found between 1384 - 1430 m, 1522 - 1720 m, 2226 - 2321 m, and 2506 - 2592 m. The discharge data available for the well is for a mass flowrate of 58 kg/s and enthalpy of 1313 kJ/kg, at a wellhead pressure of 2.5 MPag.

WELLSIM has five different two-phase flow correlations that can be used. Using the input data above, a comparison of each correlation was made with the measured downhole pressure and temperature profiles, and it was decided to use the Duns and Ros correlation, as this gave the better match for pressure and temperature above the shallowest feed zone. Probst et al. (1992) also recommend using Duns and Ros for wells exhibiting similar characteristics.

The approach used was to characterise each feed in turn, beginning with the shallowest feed and working down to the wellbottom. The possible conditions at the feed for enthalpy can be indicated by carefully studying the measured temperature profile for changes in gradient. The measured profile is Curve 4 shown in Figure 3. Based on the measured wellhead conditions, the simulated temperature profile found by assuming only a single feed at

2600 m, is Curve 1 in Figure 3. It can be seen that this starts to deviate from the measured profile below 1700 m, which is near the location of the two shallowest feed zones.

The first noticeable change in the measured temperature gradient occurs just below 1200 m, and this is most likely due to the transition from liner to casing. This conclusion is confirmed by studying the change in measured pressure gradient at this depth (see Curve 4 in Figure 4).

The measured temperature gradient continues to change below 1200 m, and this will be due to the two shallowest feeds. The enthalpy at the major feed between 1898 and 2084 m is clearly indicated by the minimal change in temperature between 1900 and 2100 m, which only varies from 288 to 289°C. Such a small change in temperature represents liquid flow, and the enthalpy of the major feed is thus the liquid phase enthalpy of pure water at 289°C, about 1280 kJ/kg. Just above 1900 m the fluid flashes.

It was decided to model the two shallowest feeds at a single point, 1400 m, as it is not really possible to distinguish between them, given the only small change in temperature gradient that is observed. The conditions of the fluid entering at this point must be such that they mix with the fluid from below, which has an enthalpy around 1280 kJ/kg, and results in a fluid which has an enthalpy of 1313 kJ/kg at the wellhead. The other constraint is that these feeds are minor feeds, so it can probably be assumed that they contribute less than half the total flow.

Performing a mass and energy balance about the 1400 m feed point, given the above constraints, provides a functional relationship between the enthalpy and mass flowrate of the feed. Various values of feed flowrate at 1400 m were tested with the simulator, and the resultant pressure and temperature profiles were compared with the measured profiles from the wellhead down to the next feed at 2100 m. The most reasonable match was found for a mass flowrate of 15 kg/s and enthalpy of 1459 kJ/kg. This result is shown in Curve 2 for both Figures 3 and 4.

To characterise the major feed at 2100 m, requires matching the pressure and temperature profiles from 2100 m to the next significant feed. If the fluid below 2100 m is in fact flowing, then from the measured temperature profile, it appears to be two-phase until a depth of around 2500 m. The temperature below this depth remains fairly constant at 318 °C, indicating an enthalpy of around 1450 kJ/kg. If the fluid were in fact static then it is less likely that the temperature gradient would remain constant.

Like the two shallow permeable feed zones, it is difficult to distinguish the two lower permeable zones. These have been modelled together at 2600 m. The conditions of the fluid entering at the major feed at 2100 m must be such that they mix with the fluid from the lowest feed at 2600 m, with an enthalpy of 1450 kJ/kg, and results in a fluid which has an enthalpy of 1280 kJ/kg above the major feed. As this feed is considered to be the major feed, it probably contributes more than half the total flow.

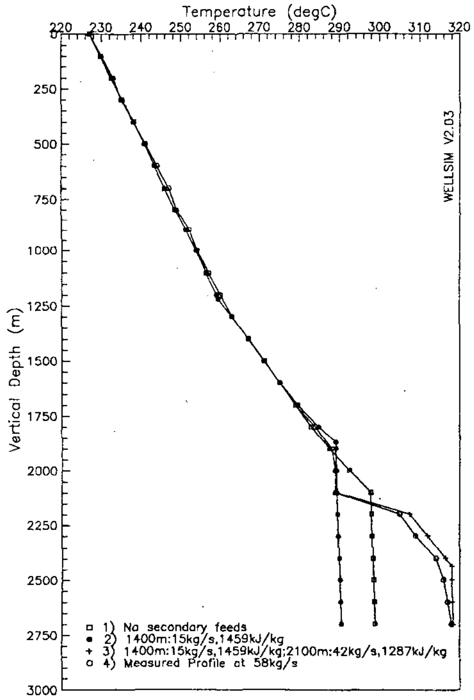

Figure 3: Simulated vs measured temperature profiles.

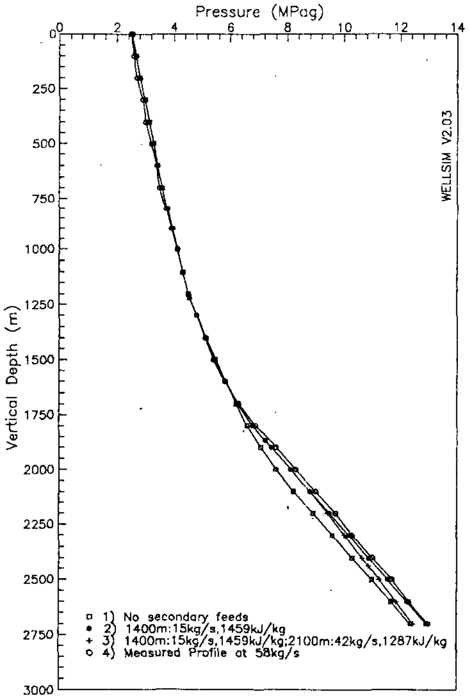

Figure 4: Simulated vs measured pressure profiles.

A functional relationship between the enthalpy and mass flowrate at the 2100 m feed point again can be derived by performing a mass and energy balance. Various values of feed flowrate at 2100 m were tested with the simulator, and the most reasonable matches were found at high mass flowrates. Conditions of 42 kg/s and 1287 kJ/kg were found to give the excellent match shown by each of Curves 3 in Figures 3 and 4. The simulated pressures are within 4.5% of the measured values from wellhead to 2600 m, and the temperatures are within 0.5%.

CONCLUSIONS

The first case study has demonstrated the use of WELLSIM to characterising reservoir/feed response relationships, and then using these relationships to compare the potential production differences between two sizes of wells. From the results, it can be inferred that wells which intersect highly permeable and productive feed zones and exhibit *wellbore controlled flow*, will benefit significantly from a large wellbore design. Where wells consistently intersect producing zones of low to intermediate permeability the additional increase is unlikely to be justified, as productivity gains are limited by the reservoir/feed response relationship.

From the second case study, it has been demonstrated that feed zone conditions can be characterised by a combination of, examining changes in the measured temperature gradient, and performing matching analyses with a wellbore simulator. Where liquid flow exists in a part of the well it becomes fairly simple to derive a relationship between the mass flowrate and enthalpy at each feed, and then use the simulator to determine the most suitable pair of flowrate and enthalpy values. It is clear that for this procedure to be successful, accurate downhole data must be available.

ACKNOWLEDGEMENTS

The authors gratefully acknowledge the management of GENZL for permission to publish this paper. Also, thanks are expressed to R.E. Tilos (PNOC-EDC, Philippines) for performing many of the simulations used for Case Study 2.

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